Control Number: 51415

Item Number: 488

Addendum StartPage: 0

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	)))))	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

Supplemental Direct Testimony and Exhibits of

Ali Al-Jabir

On behalf of

Eastman Chemical Company

May 17, 2021

BRUBAKER & ASSOCIATES, INC.

488

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	)))))	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

Table of Contents

EXHIBITS

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	)))))	BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS

Supplemental Direct Testimony of Ali Al-Jabir

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Ali Al-Jabir, 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas 78411.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am an energy consultant and an Associate with the firm of Brubaker & Associates, Inc. ("BAI").

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY ON BEHALF OF EASTMAN CHEMICAL COMPANY ("EASTMAN") IN THIS PROCEEDING?

A. Yes.

Q. WHAT ISSUES ARE YOU ADDRESSING IN YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. My supplemental direct testimony will focus on specific statements and positions taken by SWEPCO rebuttal witnesses Charles J. Locke and C. Richard Ross related to SWEPCO's inclusion of approximately $6 million of SPP transmission costs allegedly for load served by retail behind-the-meter-generation ("BTMG") in the Texas jurisdiction. Specifically, I address Mr. Locke's and Mr. Ross' statements regarding:

- Their interpretation of the SPP Tariff with respect to Network Load reporting for load served by retail BTMG;

- The treatment of load served by retail BTMG by other Regional Transmission Organizations ("RTO") and Independent System Operators ("ISO");

- Eastman's use of a single SWEPCO transmission line to tie its load and retail BTMG together; and

- FERC precedent pertaining to load served by retail BTMG.

My silence with respect to any other portion of the rebuttal testimony of SWEPCO, or SPP on behalf of SWEPCO, should not be interpreted as agreement with respect to any position taken by SWEPCO or SPP in this proceeding.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions can be summarized as follows:

1. Mr. Locke and Mr. Ross have failed to harmonize their interpretation of the ratemaking treatment under the SPP Tariff for Network Integration Transmission Service for load served by retail BTMG load with FERC's Public Utility Regulatory Policies Act of 1978 ("PURPA") standby service rules for Qualifying Facilities ("QF") including cogeneration facilities such as Eastman's retail BTMG.[1]

2. Mr. Locke's assertion that individual customer peak demands, regardless of when they occur, primarily drive transmission system investment is incorrect as it is system peak demand, and not individual customer peak demands, that primarily drives that investment as confirmed by the FERC's use of a 12 monthly coincident peak ("12-CP") demand method to allocate transmission costs to Network Integration Transmission System Service customers.

3. Mr. Locke's statements regarding the ability to undesignate an entire point of delivery to take point-to-point transmission service instead of Network Integration Transmission Service is not applicable to Eastman because: (a) Eastman is not a Network Integration Transmission Service customer of SPP; (b) SWEPCO has not offered to utilize this option on behalf of Eastman; and (c) the option is unworkable for forced outages of Eastman's retail BTMG without changes to the point-to-point notification provisions of the SPP Tariff.

4. Mr. Locke's position on the treatment of load served by retail BTMG, while representing the current position of the SPP Staff, does not represent a final position or directive of SPP.

5. Contrary to Mr. Ross' position, the SPP Staff position on the treatment of load served by retail BTMG under the SPP Tariff is not an interpretation that is binding on SWEPCO as FERC has not issued a declaratory order or a decision

[1] Eastman's retail BTMG is a both a QF and a cogeneration facility.

with respect to the treatment under the SPP Tariff for retail BTMG and, in particular, the treatment of retail BTMG that is a cogeneration facility and a QF.

6. Mr. Locke's conclusions regarding the treatment of load served by retail BTMG in other RTOs and ISOs are misleading and flawed particularly with respect to the Midcontinent Independent System Operator, Inc. ("MISO").

7. Contrary to Mr. Locke's suggestion, Eastman does not operate its retail BTMG to shave either its peak load or its load at the time of the system peak. Within the bounds of availability, it operates its retail BTMG to fully cover its load during all hours of the year.

8. Mr. Ross' focus on Eastman's use of a single SWEPCO transmission line to try to justify gross load reporting of Eastman's load that is served by its retail BTMG is misplaced and ignores the efficiency benefits associated with Eastman's use of this line versus the construction of a dedicated facility owned by Eastman.

9. The Florida Municipal Power Agency ("FMPA") and Prairieland Energy, Inc. ("Prairieland") FERC decisions cited by Mr. Locke do not apply to retail BTMG, and in particular to retail BTMG is that is a cogeneration facility and a QF. Specifically, the generation facilities in the FMPA and Prairieland cases did not involve BTMG that is committed, within the bounds availability, to operate to fully cover its load during all hours of the year. Furthermore, those cases did not require FERC to harmonize its PURPA standby service rule with its determination in those cases as neither FMPA nor Prairieland claimed their BTMG was cogeneration or a QF.

Given all the above, and also for the reasons I presented in my direct testimony, I continue to recommend:

- The Public Utility Commission of Texas ("Commission" or "PUCT") reject SWEPCO's inclusion of approximately $6 million of SPP transmission costs related to load allegedly served by retail BTMG in its Texas jurisdiction because SWEPCO's decision to include those costs is voluntary and is inconsistent with its treatment of other retail BTMG customers.

- With respect to the new transmission rate that SWEPCO proposes to recover BTMG-related costs for synchronized loads, this rate should be rejected because the transmission costs SWEPCO attempts to impose on Texas should be excluded from the revenue requirement and, as I explained in my direct testimony, it is not appropriate to impose SPP network transmission costs on the load served by retail BTMG and in particular load served by retail BTMG that is a cogeneration facility and QF such as in the case of Eastman. Therefore, the Company's proposed rate is inconsistent with proper ratemaking policy. Moreover, the proposed rate is inconsistent with cost causation principles and with the principles that govern cost allocation and rate design for retail customers with self-generation and in particular for those customers with self-generation that is cogeneration and a QF.

II. Interpretation of the SPP Tariff Language Retail BTMG

Q. WHAT ISSUES WILL YOU BE ADDRESSING IN THIS PORTION OF YOUR TESTIMONY?

A. I am addressing the following:

- Mr. Locke's and Mr. Ross' failure to harmonize their interpretation of the ratemaking treatment under the SPP Tariff for Network Integration Transmission Service for load served by retail BTMG load with FERC's PURPA standby service rules for QFs including cogeneration facilities such as Eastman's retail BTMG;

- Mr. Locke's assertion that individual customer peak demands, regardless of when they occur, primarily drive transmission system investment;

- Mr. Locke's statements regarding the ability to undesignate an entire point of delivery to take point-to-point transmission service instead of Network Integration Transmission Service;

- Whether Mr. Locke's position on the treatment of load served by retail BTMG represents a final position of SPP; and

- Mr. Ross' position that the SPP Staff position on the treatment of load served by retail BTMG under the SPP Tariff is an interpretation that is binding on SWEPCO.

Q. WHY IS IT IMPORTANT TO HARMONIZE THE FERC PURPA STANDBY SERVICE RULES WITH ANY INTERPRETATION OF THE SPP TARIFF?

A. Let me say, first, as I said in my direct testimony, I am not a lawyer and my opinions are not offered as legal opinions; however, an appreciation of the appropriate application of FERC orders and rules is a requirement in my consulting work. The FERC's PURPA standby service rules establish certain ratemaking principles that govern the manner in which standby service customers with load served from retail BTMG that is a QF must be billed for the services they receive from utilities. As I explained in my direct testimony, these rules state that standby service provided to QFs "shall not be based (unless supported by factual data) upon the assumption that forced outages or other reductions in electric output by all QFs on an electric utility's system will occur simultaneously, or during the system peak, or both."[2] These FERC standby service rules remain in full force and effect and have not been superseded by the SPP Tariff or FERC Order Nos. 888 and 890. Therefore, the SPP Tariff cannot be interpreted in a manner that bills load served by retail BTMG that is a QF in a way that invalidates or contradicts the ratemaking principles in the FERC's standby service rules.

Mr. Locke argues that gross load billing for Network Integration Transmission Service should be applied to load served by retail BTMG even if the retail BTMG is a QF.[3] The gross load billing approach assumes that QFs outages will occur during the system peak because the approach essentially assumes the QF is always out of service since it does not allow the actual output of the QF to be netted from the load. This clearly contradicts the FERC's PURPA standby service rules.

Q. SHOULD THE COMMISSION HARMONIZE THESE FERC STANDBY SERVICE OBLIGATIONS AND, IF SO, WHY?

A. Yes, it should. While I am not an attorney, it is my understanding that the PUCT has exclusive jurisdiction over retail rates and is to determine whether costs are just and reasonable and in the public interest and whether a proposed rate applicable to a retail customer is just and reasonable, as well. To determine whether SWEPCO carried its burden of proof to justify adding approximately $6 million in allocated transmission costs from SPP, and whether SWEPCO has justified applying its proposed new Transmission Rate applicable only to Eastman, the Commission should require more than claimed reliance on the testimony of an SPP Staff member focused on a justification based on FERC "precedent" that does not apply to retail BTMG, and in particular retail BTMG that is a QF. Instead, it should take into consideration and

[2] Direct Testimony of Eastman witness Ali Al-Jabir at 24 – 25 ("Al-Jabir Direct").

[3] Rebuttal Testimony of SWEPCO witness Charles J. Locke at 5 ("Locke Rebuttal").

harmonize FERC's PURPA standby service rules associated with QFs – which SWEPCO entirely ignores.

Q. REMIND US, WHAT ARE THE PURPA RULES RELATED TO QFS THAT YOU ARE REFERENCING AND WHY ARE THEY APPLICABLE TO THIS ISSUE?

A. The FERC's PURPA rules for QFs state that standby service provided to QFs "shall not be based (unless supported by factual data) upon the assumption that forced outages or other reductions in electric output by all QFs on an electric utility's system will occur simultaneously, or during the system peak, or both."[4]

Q. GIVEN THE NEED TO HARMONIZE, HOW DO YOU RECOMMEND THAT THE COMMISSION HARMONIZE THE FERC RULES AND PRECEDENT DISCUSSED BY MR. LOCKE WITH THE PURPA QF RULES?

A. The Commission should harmonize the PURPA QF rules with the FERC precedent regarding the billing for retail BTMG served by QFs by finding that net load reporting of network load should be applied to such retail BTMG.

Q. HOW DOES MR. LOCKE SUPPORT HIS OPINION THAT THE SPP CAN AND SHOULD REPORT RETAIL BTMG ON A GROSS LOAD BASIS?

A. Mr. Locke makes three statements to support his conclusion: (1) he contends that system transmission capacity must be available to serve loads with BTMG generation at all times; (2) he then suggests that individual customer peak demands drive transmission investment, which implies that system demands during all hours drive transmission costs; and (3) he suggests, erroneously, that the driver for both distribution and transmission investment is individual customer peak demands.[5]

---

[4] Al-Jabir Direct at 24 - 25.

[5] Locke Rebuttal at 13.

Q. I TAKE IT THAT YOU DO NOT AGREE WITH THESE STATEMENTS. PLEASE EXPLAIN WHY?

A. Mr. Locke's statements used to support his opinion that the SPP Tariff requires gross reporting of retail BTMG ignore the level of demand diversity that exists at the transmission level. In reality, it is the system peak demand and not individual peak demands that drive transmission costs. Individual customer peak demands are only relevant as cost drivers for more localized, lower voltage level facilities. It should be noted that Mr. Locke's statements regarding the drivers for transmission investment are inconsistent with his acknowledgment that the FERC's use of the 12 CP allocation method for transmission costs reflects the fact that utilities plan their transmission systems to meet the system coincident peak demands.[6] The principle underlying the FERC's 12 CP cost allocation method for network transmission service is that the customer demands imposed at the time of the system peak are the drivers for transmission investment. This ratemaking principle directly contradicts Mr. Locke's assertions that individual customer peak demands, regardless of when they occur, are the causal factor for transmission investment.

Q. IS THERE ANY OTHER REASON THAT YOU DISAGREE WITH MR. LOCKE'S STATEMENTS ON THIS TOPIC?

A. Yes. As discussed above, Mr. Locke's position is directly contradicted by the FERC's standby service rules that apply in this situation, which require rates be designed based on the probability that QF outages will occur at the time of the system peak. As I explained in my direct testimony,[7] the FERC's standby service rules state that a utility (*e.g.*, SWEPCO) cannot assume that all QF outages occur simultaneously or that any

---

[6] *Id.* at 4.

[7] Al-Jabir Direct at 24 - 25.

of them occur at the time of the system peak.[8] Mr. Locke's assumption that transmission capacity must be made available to fully cover QF outages at all times is inapposite of this rule. Accordingly, Mr. Locke's insistence that the FERC requires gross load reporting of QF retail BTMG is not on sound ground because he fails to account for or acknowledge the FERC's other applicable rules.

Q. ARE THERE ANY PROVISIONS IN SWEPCO'S TEXAS RETAIL TARIFF THAT CONTRADICT MR. LOCKE'S STATEMENTS LISTED ABOVE? IF SO, WHAT ARE THE PROVISIONS AND WHY ARE THEY IMPORTANT?

A. Yes, there are. SWEPCO's applicable Texas retail rate schedule for the provision of standby power requires the coordination of maintenance outages by requiring advanced notice of such outages and imposes restrictions on such outages to avoid system peak periods.[9] This requirement is important in this case because these SWEPCO tariff provisions highlight the importance of customer demands at the time of the system peaks as the drivers of the utility's investment, which again contradicts Mr. Locke's argument that individual customer peaks, regardless of when they occur, are the causal factors for transmission investments.

Q. DOES MR. LOCKE'S INTERPRETATION OF THE SPP TARIFF PROPERLY ALIGN WITH THE CIRCUMSTANCES OF RETAIL BTMG IN PARTICULAR?

A. No. Mr. Locke contends that the SPP Tariff only allows a Network Customer to exclude BTMG load from the calculation of its network load by undesignating the entire point of delivery and using point-to-point transmission service for that load.[10] In other words,

---

[8] 18 C.F.R. §292.305(c)(i).

[9] *See* SWEPCO Texas Rate Schedule for Supplementary, Backup, Maintenance and As-Available Standby Power Service, Monthly Rate, Section III, Maintenance Power Charge, which states in part, "Maintenance power may be scheduled for three occasions in a calendar year during the months of January through May and October through December for each of the Customer's generating unit(s) provided Customer provides the Company at least seven days prior notice of intent to perform maintenance."

[10] Locke Rebuttal at 5.

Mr. Locke suggests that there might be an option to not report retail BTMG load if SWEPCO were to undesignate Eastman's points of delivery from Network Integration Service and replace that with point-to-point transmission service purchased by Eastman.

Q. WHAT IS THE PROBLEM WITH HIS INTERPRETATION OF THE TARIFF AS APPLIED TO EASTMAN?

A. Eastman is not a Network Integration Transmission Service customer under the SPP Tariff. Rather, Eastman is a retail customer of SWEPCO. The distinction is important because retail customers of bundled utilities such as SWEPCO are not authorized under the SPP Tariff to undesignate their delivery points from network service and to purchase point-to-point service under the SPP Tariff. Instead, SWEPCO makes these decisions on behalf of its bundled retail customers. Therefore, as a practical matter, Mr. Locke's suggestion is not a valid option for retail customers such as Eastman, unless SWEPCO provides this option to the retail customer. SWEPCO has not offered this option to Eastman. Even if SWEPCO were to make this option available to Eastman, it is not likely to be a practical alternative in Eastman's case without modifications to the SPP Tariff due to the complications under the current SPP Tariff associated with arranging for point-to-point transmission service on short notice in the case of forced outages of Eastman's QF. Consequently, Mr. Locke's mention of this provision in the SPP Tariff is not relevant or important to the decisions that the Commission has to reach on this issue.

Q. HAS SWEPCO CONSISTENTLY APPLIED MR. LOCKE'S INTERPRETATION OF THE SPP TARIFF TO ITS RETAIL BTMG LOADS?

A. No, it has not. SWEPCO has other retail BTMG customers besides Eastman, such as retail customers that have BTMG arrangements involving natural gas, wood waste, and solar.[11] Mr. Ross admits that SWEPCO is reporting only Eastman's retail BTMG to SPP.[12]

Interesting and telling is that Mr. Locke opines in his view that small retail BTMG rooftop solar loads should be reported on a gross load basis, despite SWEPCO's indication that the Company is currently reporting such loads on a net basis.[13] SWEPCO does not report solar or any other retail BTMG load except for Eastman's load on a gross load basis. The importance for this case is that it is clear that SWEPCO is selectively applying gross load reporting to Eastman in an unduly discriminatory manner. It also highlights the fact that, while SWEPCO claims it is simply doing what SPP tells it to do, it is not. And, the reason that there are differences is because SPP does not have a directive and SWEPCO is left to interpreting the SPP Staff opinions, which leads to inconsistency and discrimination – both of which are ample reasons that SWEPCO's inclusion of approximately $6 million of allocated transmission costs for retail BTMG load should be denied. SWEPCO is voluntarily choosing to apply gross load reporting to Eastman's BTMG load while applying net load reporting to other, smaller retail BTMG loads in its service area.

Q. MR. LOCKE SPENDS A LOT OF TIME AND EFFORT STATING HIS OPINION ABOUT FERC RULES AND IMPACT OF DECISIONS TO SUPPORT HIS CONCLUSION THAT THE FERC REQUIRES GROSS RETAIL BTMG LOAD

[11] SWEPCO Response to TIEC 11-4.

[12] Rebuttal Testimony of C. Richard Ross at 12 – 13 ("Ross Rebuttal"). Mr. Ross argues that the fact that some of the BTMG loads in SWEPCO's service area are not synchronized to the grid is a factor in SWEPCO's decision to restrict gross load reporting to Eastman's BTMG load. However, the SPP Tariff makes no distinction between synchronized and unsynchronized BTMG loads with regard to transmission billing. Moreover, the fact that a BTMG is not synchronized to the grid would not necessarily in all cases prevent the load served by the BTMG from taking power from the grid when the unsynchronized BTMG is offline.

[13] *See* SWEPCO Response to TIEC 13-1(e), attached to this testimony as Exhibit AZA-4.

REPORTING UNLESS THE FERC SPECIFICALLY AUTHORIZES AN EXCEPTION.[14] DO YOU AGREE?

A. No, I do not.

Q. WHY? PLEASE EXPLAIN.

A. Based on my observations of the appropriate application of FERC Orders and precedent as a consultant, I do not believe that the Commission should give much, if any, weight to Mr. Locke's statements regarding FERC rules, precedent, or SPP's purported policy about treatment of retail BTMG for two reasons. First, Mr. Locke's testimony and opinions sets forth the SPP Staff's position on the retail BTMG issue and that is all it is – SPP's Staff's position. He does not point to a consistent clear and comprehensive directive from SPP requiring a specific treatment of retail BTMG – much less the treatment sought by SWEPCO. The simple reason is that to date, there has not been one. Mr. Locke's testimony and then Mr. Ross' reliance on those opinions should only be given the weight they deserve – the opinion of Staff. Even more telling is that the SPP Staff recognizes that the position espoused by Mr. Locke needs an SPP final decision to determine whether the SPP needs to file a request for an exemption at the FERC with respect to the load reporting of BTMG. The SPP Staff admits that SPP has not adopted a uniform, RTO-wide directive on retail BTMG and that the status quo is not clear or applied consistently.[15] The SPP Staff has not finalized any clarification or addressed how there can or will be consistent reporting and treatment of retail BTMG. At this juncture, it appears that the SPP intends to defer consideration of this issue at least until July 2021, pending SPP action with respect to the SPP's implementation of FERC Order No. 2222 regarding the participation of distribution

[14] Locke Rebuttal at 6 – 10.

[15] Ross Rebuttal at Exhibit CRR-1R, p. 41.

generation resources in the wholesale markets, which is an option that is discussed in the SPP Staff's most recent presentation on this topic.[16]

Q. WHAT IS YOUR SECOND REASON FOR WHY THE COMMISSION SHOULD NOT GIVE WEIGHT TO MR. LOCKE'S INTERPRETATIONS OF FERC ORDERS OR RULES?

A. Mr. Locke's interpretation of FERC orders or precedent reflects his opinion only. His statements are not a binding interpretation of the SPP Tariff with regard to the treatment of retail BTMG. A binding interpretation of the SPP Tariff must come through a FERC declaratory order on this topic or through a specific FERC decision interpreting the SPP's Tariff on this issue. To date, the FERC has not been asked to make a decision as to the proper treatment of *retail* BTMG under the SPP Tariff. As I explained earlier in my testimony, the precedent and cases cited by Mr. Locke are not applicable because they address wholesale BTMG and not *retail* BTMG, particularly for BTMG load served by QFs.

Q. SHOULD THE COMMISSION ACCEPT MR. LOCKE'S VIEW OF APPLYING THE FERC'S ORDERS?

A. No, it should not. In the absence of a specific FERC decision interpreting the OATT as it relates to retail BTMG, SWEPCO, SPP, and this Commission should interpret FERC's wholesale BTMG "policy" when applying it to retail BTMG in a manner that harmonizes that policy with the FERC decisions and rules applicable to the ratemaking treatment of retail BTMG that is a QF such as the facility operated by Eastman in SWEPCO's Texas service area.[17]

---

[16] Ross Rebuttal at Exhibit CRR-1R, p. 63.

[17] As noted earlier, Eastman's retail BTMG is a both a QF and a cogeneration facility.

Q. LET'S MOVE ON TO THE NEXT AREA THAT YOU TAKE ISSUE WITH MR. LOCKE'S STATEMENTS. PLEASE DESCRIBE MR. LOCKE'S STATEMENT AND YOUR DISAGREEMENT WITH HIS STATEMENT.

A. Mr. Locke contends that the SPP Tariff is consistent with the FERC's "general policy" regarding the network load reporting of BTMG load. Mr. Locke argues that the FERC's policy requires all such BTMG load to be reported on a gross load basis, unless the FERC has approved a specific exemption to this policy.[18] I do not agree with this statement because, as I have discussed, his interpretation does not recognize or attempt to harmonize FERC precedent and policy related to load served by a retail BTMG that is a QF.

Moreover, Mr. Locke acknowledges that he does not have the authority to impose his particular interpretation of the SPP Tariff on SWEPCO. As Mr. Locke states in his testimony, it is the Network Customer's (in this case, SWEPCO's) responsibility, rather than the SPP's responsibility, to ensure that its network load reporting is consistent with precedent and complies with the SPP Tariff. He also states that the SPP has no ability to verify the data submitted by Network Customers or to impose penalties for failure to provide accurate data.[19] Mr. Locke's interpretation of the SPP Tariff is not definitive, and, therefore, it does not require SWEPCO or the Commission to impose gross load reporting for Eastman's BTMG load.

Q. DOES MR. LOCKE POINT TO ANY FERC DECISION OR RULE TO DEMONSTRATE THAT THE FERC SUPPORTS HIS INTERPRETATION OF FERC POLICY WITH REGARD TO RETAIL BTMG?

A. No. Mr. Locke does not cite to any FERC-approved document or statement related to requiring gross load reporting under the OATT for retail BTMG that is a QF. The reason

[18] Locke Rebuttal at 9 – 10.

[19] Locke Rebuttal at 23.

that he cannot produce any FERC precedent on this exact issue is because there is none.

Q. DO YOU HAVE ANY IDEA AS TO WHAT MR. LOCKE MIGHT BE RELYING ON IN REACHING HIS CONCLUSION?

A The only thing I can surmise is that, in support of his misplaced conclusion, Mr. Locke is relying on discussions that took place at a meeting in January 2018 between FERC Staff and SPP Staff during which the FERC Staff allegedly interpreted the FERC's policy as requiring gross load reporting of BTMG in the absence of the FERC's approval of a specific exemption to this alleged "general rule."[20] However, it is my understanding that Mr. Locke was not present at the meeting, so the content of that meeting is not direct knowledge of what was discussed at that meeting.[21]

Q. EVEN IF WE IGNORE THAT MR. LOCKE WAS NOT AT THE MEETING AND, THEREFORE, DID NOT HAVE FIRST HAND KNOWLEDGE OF THE DISCUSSION, SHOULD THE COMMISSION RELY ON A DISCUSSION BETWEEN FERC STAFF AND SPP STAFF TO JUSTIFY APPROXIMATELY $6 MILLION OF NEW TRANSMISSION COSTS?

A. No, for several reasons First, regardless of any discussion that took place during this meeting, it really is of no value in deciding the issue presented to the PUCT because a meeting between staff members is not FERC policy, opinion, or rule interpretation – it is simply a discussion. The informal meeting was apparently between one or more members of the FERC Advisory Staff and SPP Staff[22] – neither of which have decision-

---

[20] *See* Exhibit AZA-3, which is a true and correct copy of SWEPCO Response to TIEC 13-8.

[21] Eastman issued a Third Set of RFIs on May 11, 2021, related to the meeting discussed in TIEC 13-8. As of the date of filing my supplemental testimony, I do not have the responses. I reserve the right to revise my testimony to the extent that additional facts are uncovered in the SWEPCO responses.

[22] Exhibit AZA-3 (SWEPCO Response to TIEC 13-8). A reference is made to John Rogers with the FERC Staff, but there is no explanation of his title or his role at the FERC related to BTMG reporting.

making authority. And, it is telling that when pushed for any correspondence between SPP and the FERC relating to retail BTMG, Mr. Locke admits that there is none.[23] The informal opinion of some FERC Staff members does not constitute a binding interpretation of the SPP Tariff or FERC precedent on this issue. Such a binding interpretation must come in the form of a FERC declaratory order or a FERC decision interpreting the SPP Tariff in the context of retail BTMG, particularly for QFs and cogeneration facilities in general. SWEPCO has not provided such a decision or order. And, as a result, a meeting between Staff members does not help in any way to resolve this dispute.

Second, even if the meeting was helpful or instructive, we have little information about this meeting from SWEPCO. Mr. Locke's secondhand description of the meeting was very cursory – which is understandable since Mr. Locke apparently did not attend the meeting himself and, therefore, his understanding of the meeting is necessarily limited.[24]

Third, it is not clear whether, at this meeting, the FERC Staff representative's interpretation of the SPP Tariff applied in the specific context of *retail* BTMG that is a QF or a cogeneration facility (which is the issue before this Commission), as opposed to treatment of wholesale BTMG in the context of the SPP Tariff language governing network load reporting. This distinction remains important. As I explained in my direct testimony, there are significant differences in the operational characteristics of wholesale versus retail BTMG, particularly in the case of retail BTMG that is a QF or a

---

[23] Exhibit AZA-3, which is a true and correct copy of SWEPCO's Response to TIEC RFI No. 13-7.

[24] *See*, Exhibit AZA-3. SWEPCO's response to TIEC 13-8 summarizes the conclusions taken from the meeting in only two brief sentences: "The guidance from John Rogers was that SPP's interpretation of FERC rules and orders on netting of behind the meter generation was correct. Further, for netting of behind the meter to be authorized a filing must be made and approved by FERC before netting is allowed."

cogeneration facility such as Eastman's facility, which make it appropriate to apply netting of retail BTMG load.[25]

Q. MR. ROSS CONTENDS THAT THE COMPANY IS APPLYING GROSS LOAD REPORTING TO EASTMAN'S BTMG LOAD BECAUSE IT IS REQUIRED BY SPP TO DO SO.[26] HOW DO YOU RESPOND?

A. Mr. Ross is wrong. SWEPCO is trying to hide behind SPP to explain why it decided to change its treatment of retail BTMG in October 2018 (with no change in its Tariff). But, Mr. Locke acknowledged that the responsibility to apply the SPP Tariff for BTMG load reporting purposes ultimately rests with SWEPCO.[27] Importantly, the legal authority to interpret the SPP Tariff rests with the FERC rather than the SPP Staff. Moreover, as I discussed in my direct testimony, the responses to the SPP's BTMG surveys of its members demonstrate that network customers in the SPP are not applying a uniform approach.

Q. ARE THERE ANY OTHER INDICATIONS THAT SWEPCO MADE ITS OWN DECISION AS TO CHANGING ITS REPORTING POLICY FOR RETAIL BTMG LOADS?

A. Yes. First, it is undisputed that some SPP Network Customers are not reporting retail BTMG. Mr. Locke admits that in his testimony.[28] Some survey respondents specifically indicated that they continue to report retail BTMG on a net load basis. Even the SPP Staff as late as January 2021 recognized that reporting of retail BTMG is not consistent.[29] Second, as I discussed earlier in my testimony, SWEPCO is selectively

---

[25] Al-Jabir Direct at 18.

[26] Ross Rebuttal at 7-8.

[27] Locke Rebuttal at 23.

[28] Locke Rebuttal at 23.

[29] Ross Rebuttal at Exhibit CRR-1R at 41: "There is a continuing lack of clarity and/or difference of understanding regarding the treatment of BTMG in the context of Network Load reporting. This leads to inconsistencies in the amount of load reported by Network Customers."

applying gross reporting of BTMG load to Eastman, while applying net load reporting to smaller rooftop solar loads (*e.g.*, not including these BTMG loads in its network load reporting). All of this indicates that SWEPCO alone decided how it would report load served by retail BTMG, without any formal, uniform SPP directive.

III. Treatment of Retail BTMG in Other RTOs/ISOs

Q. IS MR. LOCKE'S INTERPRETATION OF FERC POLICY WITH REGARD TO RETAIL BTMG CONSISTENT WITH THE PRACTICES OF OTHER REGIONAL TRANSMISISON ORGANIZATIONS ("RTOs") AND INDEPENDENT SYSTEM OPERATORS ("ISOs")?

A. No. In my direct testimony, I provided examples of other RTOs' and ISOs' practices and policies that are different than those of SPP.[30] Mr. Locke asserts that the FERC requires approval of a specific Tariff exemption to allow for netting of retail BTMG load.[31] However, his opinion is inconsistent with the practices of the Midcontinent Independent System Operator ("MISO"). In MISO, netting of BTMG is being permitted without a FERC Order approving specific Tariff language that authorizes netting of BTMG.

Q. LET'S LOOK INTO YOUR ANALYSIS FURTHER. REMIND US WHAT MISO PROVIDES WITH RESPECT TO REPORTING OF RETAIL BTMG AND HOW IT CAME TO THAT DECISION?

A. In the case of MISO, the QF Integration Plan approved by MISO for MISO South allows for the netting of retail BTMG for QFs. This is the QF Integration Plan that was the subject of the FERC's order in the Occidental Chemical Corporation case, which I

[30] Al-Jabir Direct at 19 – 22.

[31] Locke Rebuttal at 8 – 10.

discussed in my direct testimony.[32] This QF Integration Plan specifies that the Entergy operating companies should designate the net withdrawals of QFs in their service areas as network load.[33] A copy of this QF Integration Plan is attached to my testimony as Exhibit AZA-5. Therefore, utilities in MISO South, such as Entergy, have long applied and continue to apply netting to retail BTMG. MISO is aware of this practice and it is allowing it to continue in MISO South, as well as elsewhere in the MISO footprint,[34] as a compromise decision that essentially allows each transmission owner in MISO to maintain its own load reporting practices for BTMG.[35] This example contradicts Mr. Locke's assertion that the FERC has interpreted its prior orders to require a specific Tariff exemption approved by the FERC in order to implement net load reporting of retail BTMG load.

Q. WHAT IS THE IMPORTANCE OF MISO'S QF INTEGRATION PLAN?

A. I am not an attorney, but, as I understand it, the important aspect is that MISO, on its own, adopted the QF Integration Plan without any FERC requirement or permission. The Plan said that Entergy should report its BTMG load served by QFs on a net load basis. Therefore, net load reporting for this retail BTMG is in effect in MISO in the absence of a FERC tariff exception authorizing such reporting.

---

[32] *Occidental Chemical Corp. v. The Midwest Independent System Operator, Inc.*, Order Denying Complaint, 155 FERC ¶ 61,068 at 76 (2016).

[33] Qualifying Facilities (QF) Generator Readiness for MISO Reliability Coordination and Market Integration, October 10, 2012 at 17-18.

[34] Other examples I am aware of MISO transmission owners who have historically reported load served by retail BTMG to MISO on a net basis include ITC-Transmission in Michigan, METC in Michigan, ITC-Midwest in Iowa and NIPSCO in Indiana.

[35] *See* MISO Presentation, BTMG/btmg Gross vs. Net Load for NITS Billing, Planning Advisory Committee, October 16, 2019.

Q. DOES MR. LOCKE ACCURATELY EXPLAIN MISO'S POSITION WITH RESPECT TO THE TREATMENT OF RETAIL BTMG?

A. No. Mr. Locke contends that MISO's presentation materials support gross load reporting of all BTMG loads.[36] However, Mr. Locke's discussion of these MISO presentation materials is misleading because he has not explained these materials in full context. Specifically, the MISO presentation language cited by Mr. Locke was posted in the context of evolving stakeholder discussions regarding the treatment of retail BTMG, and the cited language was selectively taken from certain MISO BTMG proposals that MISO Staff floated for stakeholder feedback.[37] Other parts of these same presentations that Mr. Locke did not discuss demonstrate that MISO ultimately supported a netting approach for retail BTMG, and it recognized that a number of the MISO Transmission Owners have long reported their network load net of retail BTMG output.[38]

Q. DO YOU HAVE ANY SPECIFIC EXAMPLES?

A. Yes, for example, it is correct that on September 27, 2017, MISO's legal staff gave a presentation to the MISO Planning Advisory Committee ("PAC") suggesting that all load (both retail and wholesale), except curtailable load, that is served by BTMG should be reported on a gross load basis. However, MISO's interpretation of its own Tariff at that time was flawed.[39] Through its own process with input from all customers/stakeholders, and as I discussed earlier in my testimony, MISO ultimately decided on a compromise

---

[36] Locke Rebuttal at 16-18.

[37] Locke Rebuttal at 17.

[38] MISO presentation, BTMG/btmg Gross vs. Net Load for NITS Billing, Planning Advisory Committee, October 16, 2019, page 2: "One approach does not fit all customer circumstances. MISO tariff does not impact retail tariffs or external agreements impacting retail load treatment."

[39] Association of Businesses Advocating Tariff Equity, Coalition of MISO Transmission Customers, Illinois Industrial Energy Consumers, Louisiana Energy Users Group, Midwest Industrial Customers and Texas Industrial Energy Consumers, Comments on MISO's Proposed Treatment of BTMG/btmg, October 18, 2017.
https://cdn.misoenergy.org/20191016%20PAC%20Item%2003c%20BTMG%20(PAC003)390699.pdf

that allowed net load reporting of retail BTMG to continue where permitted by transmission owners.[40] This compromise required no change to the MISO Tariff.

Q. DO YOU HAVE ANOTHER EXAMPLE?

A. Yes, I do. Mr. Locke notes that MISO's February 13, 2019 presentation to the MISO PAC used the words "existing requirements" in reference to gross load reporting when it was discussing MISO Option 2.[41] However, on that same slide (Slide 4), MISO recognized that:

- The historic practice of a number of MISO Transmission Owners was to apply net load reporting at least with respect to QFs, and that this practice would be given a tariff waiver under MISO Option 2.

- The FERC standby service rules for QFs seem to support the netting of QF retail BTMG load.

Then on a different slide in the presentation (Slide 2), MISO said that it [is] "swayed by arguments for uniform netting for billing associated with retail btmg".

Q. WHAT IS THE IMPORTANCE OF THIS DISCUSSION AS IT RELATES TO MISO'S TREATMENT OF RETAIL BTMG REPORTING?

A. As I have noted, the ultimate product of all of the foregoing stakeholder discussions at MISO was a compromise that allows each transmission owner utility in MISO to maintain its own load reporting practices for BTMG – again, a compromise that required no modification to the MISO Tariff. Hence, MISO implicitly conceded that there is not an existing requirement under its Tariff to report load served by retail BTMG on a gross load basis despite what it may have indicated on February 13, 2019. Accordingly, Mr. Locke's comments regarding MISO are incorrect.

---

[40] MISO presentation, BTMG/btmg Gross vs. Net Load for NITS Billing, Planning Advisory Committee, October 16, 2019. https://cdn.misoenergy.org/20191016%20PAC%20Item%2003c%20BTMG%20(PAC003)390699.pdf

[41] *Compare* Locke Rebuttal at 17 *with* https://cdn.misoenergy.org/20190213%20PAC%20Item%2003a%20BTMG-btmg%20(PAC003)318041.pdf.

IV. Eastman's Use of the SPP Transmission System

Q. ARE THERE STATEMENTS MADE BY MR. LOCKE RELATED TO EASTMAN'S USE OF THE SPP TRANSMISSION SYSTEM THAT YOU WANT TO ADDRESS?

A. Yes. Mr. Locke contends that gross reporting of BTMG load is justified to prevent customers (apparently like Eastman) from avoiding cost responsibility for transmission service by strategically using their retail BTMG to reduce or to eliminate their use of the transmission system at the time of the system peak.[42]

Q. HOW DO YOU RESPOND?

A. Mr. Locke's argument is theoretical, at best, but it has no merit in this case because Eastman does not use its BTMG for peak shaving in the manner that he suggests. It is important to remember, which apparently Mr. Locke does not, that Eastman operates a continuous chemical manufacturing facility at its site in the SWEPCO Texas service area. The primary objective of Eastman's on-site cogeneration facility is to provide a reliable, constant, efficient, and economical source of steam – steam it cannot produce without running its retail BTMG and its associated heat recovery facilities. Therefore, Eastman has a strong interest in maximizing the operation of its on-site generation and in reducing the frequency of generator outages.

As a result, Eastman runs its BTMG to fully cover its load during all hours when the generation is available, and Eastman schedules its planned BTMG outages during off-peak periods – as a responsible customer should do. Eastman's BTMG is used to cover Eastman's load during all system peak hours, except in those rare circumstances that Eastman's BTMG experiences a forced outage – which may or may not occur at the time of the system peak. Other retail BTMG customers with on-site QFs or cogeneration would typically operate their BTMG in the same manner. Therefore, this

---

[42] Locke Rebuttal at 12-13.

peak shaving concern is not applicable to retail BTMG loads served by QFs such as Eastman. Mr. Locke did not provide any documentation or information that would indicate that Eastman conducts its operations in such a manner.

Q. IF A RETAIL CUSTOMER'S BTMG EXPERIENCED AN UNSCHEDULED OR FORCED OUTAGE DURING THE SYSTEM PEAK IN A GIVEN MONTH, WOULD THE CUSTOMER'S LOAD BE INCLUDED IN NETWORK LOAD REPORTS FROM SWEPCO TO SPP IN THAT MONTH WITHOUT THE NEED FOR GROSS REPORTING OF THE ENTIRE LOAD IN EVERY MONTH?

A. To the extent that a retail customer's BTMG experiences a forced outage during the system peak in a given month, the retail customer's load, including BTMG load, would be included in the Network Customer's network load to SPP reporting for that month. As a result, under the FERC's 12-CP load ratio share allocation method for network transmission costs, over time the retail BTMG customer will pay for transmission service based on its expected demand at the time of the system peak, which is the product of the retail customer's equivalent forced outage rate for its BTMG and its gross demand. This is a reasonable outcome that aligns with the FERC's standby service rules for QFs.[43] These rules specify that charges for QFs should be based on the probability that they will experience an outage at the peak and not on an assumption that all QF outages will occur at the time of the peak (the latter outcome is the result of SWEPCO's gross reporting of Eastman's retail BTMG load).

---

[43] 18 C.F.R. §292.305(c)(i): The FERC's PURPA rules for QFs state that standby service provided to QFs "shall not be based (unless supported by factual data) upon the assumption that forced outages or other reductions in electric output by all QFs on an electric utility's system will occur simultaneously, or during the system peak, or both."

Q. ARE THERE ANY STATEMENTS BY MR. ROSS REGARDING EASTMAN'S USE OF THE SPP TRANSMISSION SYSTEM THAT YOU WANT TO ADDRESS?

A. Mr. Ross argues that Eastman's limited use of the SPP transmission system justifies reporting Eastman's BTMG load on a gross basis.[44] I do not agree with his conclusion.

Q. PLEASE EXPLAIN WHY YOU DO NOT AGREE WITH HIS STATEMENT.

A. Eastman's use of the SPP transmission system to serve a portion of its BTMG load is limited to a single line and over a relatively short distance. Therefore, the use of this single line is nothing more than an incidental use of SWEPCO's transmission facilities. Eastman attempted to acquire this transmission line and the South Texas Eastman substation from SWEPCO, but SWEPCO refused to sell these facilities to Eastman.[45] In fact, Eastman's use of this single SWEPCO transmission line to serve Eastman's retail BTMG load is more efficient for Eastman, SWEPCO and SWEPCO's customers than constructing a new transmission line to serve the entirety of Eastman's BTMG load because it avoids the duplication of facilities. Therefore, this limited and incidental use of a single SWEPCO transmission line in the interests of system efficiency does not constitute a use of the integrated SPP transmission system to an extent that would justify gross load reporting of Eastman's BTMG as alleged by Mr. Ross to the tune of an additional $3.96 million per year for Eastman to pay SWEPCO. The $3.96 million figure is the amount that SWEPCO proposes to recover from Eastman through the new synchronized self-generation rate.

Q. IS MR. ROSS' STATEMENT RELEVANT TO THE DISPUTES IN THIS PROCEEDING?

A. No, Mr. Ross' argument in this regard is a red herring. The Company is taking the position that all BTMG load must be reported on a gross load basis under the SPP

[44] Ross Rebuttal at 10-11.

[45] Eastman's Response to SWEPCO 2-1(c).

Tariff, irrespective of whether that load uses individual SWEPCO transmission facilities. SWEPCO decided that it would start reporting Eastman's retail BTMG on a gross load basis irrespective of whether the load used SWEPCO or SPP facilities to serve a portion of the BTMG load.

V. <u>FERC Precedent Pertaining to Retail BTMG</u>

Q. YOU HAVE ADDRESSED SEVERAL CONCLUSIONS AND STATEMENTS MADE BY MR. LOCKE EARLIER IN YOUR TESTIMONY. TO COMPLETE YOUR SUPPLEMENTAL TESTIMONY, WHAT DO YOU WANT TO ADDRESS?

A. I do not believe that Mr. Locke has correctly interpreted FERC rate case precedent with respect to the treatment of retail BTMG. I will respond to his statements regarding the Florida Municipal Power Agency ("FMPA") decision and the Prairieland Energy decision.

Q. LET'S FIRST TURN TO THE FMPA CASE. HAS MR. LOCKE CORRECTLY INTERPRETED THIS CASE?

A. No. Mr. Locke cites to the FMPA case at FERC to support the argument that the FERC's general position is that gross load reporting of BTMG is required under FERC policy.[46] Mr. Locke is completely wrong in citing this FERC Order because the FMPA case applies to wholesale BTMG involving a municipal electric utility system's generation facilities; it does not relate or pertain at all to retail BTMG.[47] As you will recall, in my direct testimony, I explained the significant difference between wholesale

---

[46] Locke Rebuttal at 7, citing *Florida Mun. Power Agency v. Florida Power & Light Co.*, 67 FERC ¶ 61167, 61482 n. 77 (May 1994).

[47] *Florida Mun. Power Agency* at 22 ("compensation for the network transmission service should not be driven by FMPA's hourly economic dispatch decisions.") Eastman's BTMG is not economically dispatched for the generation that serves its local load. Rather, the BTMG is used to serve the local load in all hours when it is available. Operation of BTMG based on economic dispatch decisions is characteristic of wholesale BTMG.

and retail BTMG.[48] The FERC's FMPA decision does not apply to load served by retail BTMG.

Q. DOES EASTMAN'S RETAIL BTMG OPERATE IN THE SAME MANNER AS FMPA's WHOLESALE BTMG?

A. No, it does not. Eastman's BTMG runs to fully serve its load during all hours when it is available. In sharp contrast, FMPA's wholesale BTMG, as utility generation, would be dispatched to serve FMPA's load only when it is necessary for reliability or economic to do so. Eastman only very rarely takes power from SWEPCO, which would not necessarily be the case for FMPA's wholesale BTMG. Specifically, Eastman only takes power from SWEPCO for its load when Eastman experiences an outage of its BTMG. Significantly, operating data provided by Eastman shows that it only took power from SWEPCO during 2.4% of the time intervals over the period 2016-2020 for both maintenance, scheduled outages and unexpected or forced outages. This data is summarized in Exhibit AZA-6.[49] This data demonstrates that there is a very low probability that Eastman will rely on power imports from SWEPCO to serve its BTMG load at the time of the system peak. I contrast that with a wholesale BTMG customer that may rely on the grid at any time if it is more economic to purchase power from the wholesale market than to provide the required power from its own BTMG. This type of transmission use can occur at any time, including at the system peak or at the time of near system peak conditions.

---

[48] Al-Jabir Direct at 18.

[49] Exhibit AZA-6 is highly confidential protected material and filed under seal except for the "Percentage of Year" calculation. The data, which is provided as a workpaper to my testimony (sealed as highly confidential protected material), shows power imports and exports as recorded on Eastman's meters during periods of maintenance and forced outages for the study period. Periods of net power imports reflect periods of time when Eastman was drawing power from SWEPCO to cover its local load requirements. Maintenance power is taken when an on-site generation unit experiences a planned outage to perform scheduled maintenance, while backup power is taken when an on-site generation unit experiences an unscheduled, forced outage due to equipment failure or similar causes.

Q. DID THE FMPA CASE ADDRESS RETAIL BTMG INVOLVING QFS OR COGENERATION FACILITIES?

A. No, and it is important to understand this distinction. As I have noted, in the FMPA case, the FERC was looking at wholesale BTMG that a municipal utility in Florida used only when it was economical to do so relative to purchasing power from the grid. As a result, the FERC did not have to harmonize or address reporting BTMG with the FERC QF standby rules. In fact, the FERC was not dealing with retail BTMG involving QFs or cogeneration facilities, such as Eastman's facilities, at all; it was focused on FMPA, which is a utility that operates at wholesale. For retail BTMGs with QFs, the FERC's QF standby service rules must be applied and harmonized with the load reporting of BTMG.[50] As I discussed earlier in my testimony, such harmonization requires netting for the network load reporting associated with retail load that is served behind the meter by QFs. Applying gross load reporting to retail BTMG loads served by QFs would imply an assumption that QFs are very likely to, if not always, experience outages at the time of the system peak, which directly contradicts the FERC's QF standby service rules.

Q. YOU MENTIONED THAT YOU ALSO WANTED TO ADDRESS MR. LOCKE'S STATEMENTS REGARDING THE PRAIRIELAND CASE. PLEASE EXPLAIN MR. LOCKE'S STATEMENTS AND WHAT YOU TAKE ISSUE WITH? WHAT ABOUT THE PRAIRIELAND ENERGY CASE THAT MR. LOCKE DISCUSSES?

A. Mr. Locke alleges that the FERC's decision in the Prairieland case supports his position that network customers, such as SWEPCO, must pay for network service on a gross

---

[50] 18 C.F.R. §292.305(c)(1).

load basis.[51] However, Mr. Locke misapplies that precedent because the facts in the Prairieland case do not fit the Eastman facts in the current proceeding.

Q. PLEASE EXPLAIN.

A. The FERC's decision in the Prairieland case determined that netting of BTMG should not be applied in the specific context of Load Modifying Resources ("LMRs") that are also registered with MISO as Behind the Meter Generation (LMR BTMG as a capitalized term).[52] Prairieland's BTMG was designated as an LMR BTMG under the MISO Tariff. Under MISO's procedures, LMR BTMG is only obligated to provide power to serve its behind the meter load when called upon during MISO Maximum Generation Events, which occur rarely. Moreover, at least a portion of Prairieland's on-site generation dates back to 1967 and thus predates PURPA. As such, it would not likely be a QF. Furthermore, Prairieland did not claim its generation was a QF.

By contrast, Eastman's generation is not used to provide power only occasionally to serve its BTMG load, as is the case with Prairieland. Instead, Eastman's BTMG is operated continuously to serve its behind the meter load whenever it is available to do so. Eastman's QF generation is not some form of emergency reliability resource as was true with Prairieland. It is the primary source of power for a major manufacturing facility that runs 24 hours a day, every day. This makes it much less likely that Eastman would rely on the transmission grid to serve its on-site load requirements relative to Prairieland. Furthermore, Eastman's BTMG is a QF, while the

[51] Locke Rebuttal at 7-8, citing *Ameren Services Co.*, 131 FERC ¶ 61,125 (2010)("Prairieland Case").

[52] *Ameren Services Co.*, 131 FERC ¶ 61,125 (2010).

Prairieland generation is not. Therefore, the FERC's standby service rules for QFs apply to Eastman, but they do not apply to Prairieland.

For the reasons summarized above, the facts in the Prairieland case do not apply to Eastman's situation. Specifically, Eastman's BTMG is a QF that operates as much as possible to serve its on-site load, and it is not registered as an LMR BTMG. By contrast, Prairieland's BTMG is only used to serve its local load for limited times during MISO emergencies or when it is economic for Prairieland to utilize the generation.

As I discussed earlier in my testimony, MISO has explicitly allowed for the netting of retail BTMG in its QF Integration Plan for MISO South, and it has decided on a compromise that allows individual utilities throughout MISO to continue their long practice of netting retail BTMG load in their network load reporting. Furthermore, MISO found that it was unnecessary to seek FERC approval of any changes to its current Tariff in order to continue the practice of net load reporting for retail BTMG pursuant to this compromise. Therefore, it is clear that MISO has not interpreted the Prairieland decision as barring it from allowing netting for load served by retail BTMG that is a QF.

Q. MR. AL-JABIR, WITH THE ADDITIONAL TESTIMONY OF MR. LOCKE AND MR. ROSS, ARE THERE ANY OF YOUR RECOMMENDATIONS IN YOUR DIRECT TESTIMONY THAT SHOULD BE CHANGED?

A. No. If anything, Mr. Locke's opinions as an SPP Staff member and his failure to identify any specific directive from SPP that is being applied consistently and equally to all retail BTMGs further bolsters my recommendation that the Commission should disallow the approximate $6 million in SPP allocated transmission costs that supposedly are attributable to Eastman's retail BTMG load. In addition, Mr. Ross does not provide any credible rationale as to how SWEPCO's decision to report gross loads is just or reasonable or how such a decision and allocation of costs is consistent with cost causation principles. Finally, neither Mr. Locke's nor Mr. Ross' testimony bolster or support SWEPCO's proposed new transmission rate that is solely applicable to Eastman's contractual (and not even actual) retail BTMG load. As a result, my recommendations remain the same, but I am very appreciative of being provided an opportunity to respond to their testimony.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes, it does, although I reserve the right to supplement this testimony upon receipt of the additional information requested in Eastman RFI 2-3 which, under Order No. 11, SWEPCO has yet to produce.

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

Affidavit of Ali Al-Jabir

State of Texas)
) **SS**
County of Nueces)

Ali Al-Jabır, being first duly sworn, on his oath states:

1. My name is Ali Al-Jabir. I am an Associate with Brubaker & Associates, Inc.; 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas 78411. We have been retained by Eastman Chemical Company to testify in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Supplemental Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Public Utility Commission of Texas Docket No. 51415.

3. I hereby swear and affirm that my answers contained in the testimony are true and correct.

Ali Al-Jabir

Subscribed and sworn to before me this 13th day of May, 2021.

Amy Morin
Notary Public

My Commission expires on 08/29/2023

AMY MORIN
My Notary ID # 6349873
Expires August 29, 2023

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 13-7:

Please provide all correspondence between SPP and FERC relating to retail BTM generation since January 2016.

Response No. TIEC 13-7:

There are none.

Prepared By: Charles J. Locke	Title: SPP, Dir Transmission Policy & Rates
Sponsored By: Charles J. Locke	Title: SPP, Dir Transmission Policy & Rates

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 13-8:

Identify any meetings or telephone calls between SPP and FERC relating to the treatment of retail BTM generation since January 2016. Include the date, time, names of participants, and substance of any such communications.
To the extent that SPP received any guidance or direction from FERC concerning this issue, state the name and title of any person providing such guidance and the specific statements made.

Response No. TIEC 13-8:

On January 10, 2018 at 2:00 p.m., SPP staff members Paul Suskie and Sam Loudenslager participated in face-to-face meeting at the Federal Energy Regulatory Commission ("FERC") to discuss behind the meter generation and netting with FERC staff. The attendees included Paul Suskie and Sam Loudenslager from SPP and John Rogers and potentially others from FERC. Meeting calendar invites only indicate that John Rogers was invited but recollection is other FERC employees were in the room that report to John Rogers at FERC. The guidance from John Rogers was that SPP's interpretation of FERC rules and orders on netting of behind the meter generation was correct. Further, for netting of behind the meter to be authorized a filing must be made and approved by FERC before netting is allowed.

Prepared By: Charles J. Locke — Title: SPP, Dir Transmission Policy & Rates

Sponsored By: Charles J. Locke — Title: SPP, Dir Transmission Policy & Rates

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' THIRTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 13-1:
The following questions refer to the Rebuttal Testimony of Charles Locke:

Please refer to SWEPCO's response to TIEC-5-3. Please state whether SWEPCO's response to each of the 5 subparts properly reflects Mr. Locke's understanding of the proper treatment of the identified customer in SWEPCO's reporting of monthly
peak load data to SPP. If the answer for any subpart is anything other than an unequivocal Yes, please explain why in detail and state for each subpart the amount that Mr. Locke believes SWEPCO should report in its monthly peak load data.

Response No. TIEC 13-1:

Mr. Locke's answer follows SWEPCO's answer for each subpart as follows:

a. SWEPCO's answer: 0 MW for this customer.
Mr. Locke's answer: 0 MW should be included in Network Load.

b. SWEPCO's answer: 10 MW for this customer.
Mr. Locke's answer: 10 MW should be included in Network Load.

c. SWEPCO answer: 50 MW if the behind the meter generator was serving that load at the time of the peak.
Mr. Locke's answer: 50 MW should be included in Network Load if the behind-the-meter generator was serving 50 MW in the hour of the peak.

d. SWEPCO's answer: 50 MW if the behind the meter generator was serving that load at the time of the peak.
Mr. Locke's answer: 50 MW should be included in Network Load if the behind-the-meter generator was serving 50 MW in the hour of the peak and assuming that the facility associated with the 50 MW load is at any time electrically connected to the Network Customer's Point of Delivery.

e. SWEPCO answer: 10 kW because SWEPCO has not made any adjustments for such loads in its reporting to SPP at this time
Mr. Locke's answer: 20 kW should be included in Network Load because that is the customer's total load in the hour of the peak.

Prepared By: Charles J. Locke — Title: SPP, Dir Transmission Policy & Rates

Sponsored By: Charles J. Locke — Title: SPP, Dir Transmission Policy & Rates

Qualifying Facilities (QF) Generator Readiness for MISO Reliability Coordination and Market Integration

---

Prepared by MISO
10/10/2012

P.O. Box 4202
Carmel, IN 46082-4202
Tel: 317-249-5400
Fax: 317-249-5703

www.misoenergy.org

Contents

DISCLAIMERS

This reference is prepared for discussion and information purposes and provided "as is" without representation or warranty of any kind, including without limitation, accuracy, completeness or appropriateness for any particular purpose. MISO assumes no responsibility for the consequences of any errors or omissions. MISO may revise or withdraw this reference at any time at its discretion without notice. Even though every effort will be made by MISO to update these references and inform its membership of changes, it is the user's responsibility to ensure you are using the most recent edition.

Document Change History

Version	Reason for Issue / Change	Date
1.0	Initial Release of Document	October 9, 2012

Executive Summary

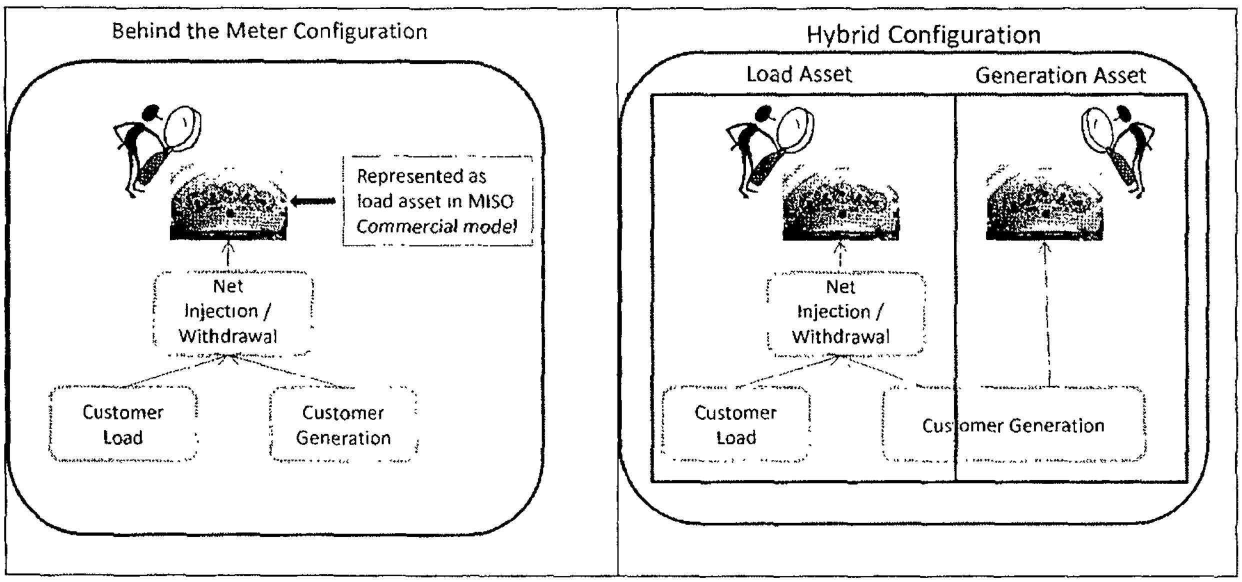
In February of 2012, MISO published the "Qualifying Facilities in MISO: Exploratory Whitepaper" in order to provide context and direction to Qualifying Facilities (QFs) in the Entergy service territory. QFs may enjoy certain benefits under Federal, State and local laws. The benefits that are conferred upon QFs by Federal law generally fall into three categories: (1) the right to sell energy or capacity to a utility or into the wholesale market, (2) the right to purchase certain services from utilities, and (3) relief from certain regulatory burdens. These PURPA benefits to which the QFs are entitled do not apply to other generators or loads. This document is a follow-up to the February 2012 paper and provides information for QFs transitioning into the MISO Reliability Coordination (RC) Area. In addition, this document provides information for QFs that desire to participate in MISO's Market Operations, and describes readiness requirements.

Section 1: Configuration Options for QFs within MISO

Entergy customers that own generation have two possible configurations for interacting with their local utility (Entergy Arkansas, Inc., Entergy Gulf States Louisiana L.L.C., Entergy Louisiana LLC., Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc.). There are different requirements associated with registration, metering, telemetry, and market participation with each of these alternatives.

As an initial matter, it is important to note that MISO maintains two separate models of the regional Bulk Electric System (BES): a Network Model and a Commercial Model. MISO uses the Network Model in its role as the Reliability Coordinator (RC) for the region. As subsequently discussed in more detail, as the RC, MISO has the Federally-mandated legal authority to take the steps necessary to ensure the reliability of the BES, which means that MISO can require generators that can affect the BES to register and provide both static and real-time data to its Network Model. The criteria that define which generators are obligated to register in the Network Model are discussed below. The Commercial Model, on the other hand, is used to manage and price transactions in the Energy, Operating Reserves, and Ancillary Services markets run by MISO. Generators must register for the Commercial Model if they want to sell energy, capacity, or ancillary services in the day-ahead or real-time MISO markets.

QFs have two general alternative configurations for interacting with MISO and their local utility: a Behind the Meter (BTM) option and a Hybrid option. These options are graphically described in Figure 1:



Behind the Meter customers that want to remain behind the meter and not participate in the MISO markets (i.e., customers that choose to continue to "put" unscheduled, as-available energy to their incumbent Entergy Operating Company) do not have to register their generation in the Commercial Model. Information needed from BTM generation, however, generally is the same as that needed in the Network Model in order for MISO to meet its obligations as the Reliability Coordinator.

Modeling Requirements

The following table depicts the threshold requirements for generators and whether the source of the requirement is RC or Market. Each requirement is discussed in greater detail below.

Threshold MVA Nameplate Rating	Applies to...	Reliability Coordination	Market / Balancing Authority Area	Comments
› 80MVA	Individual Generator or Gross Plant / Facility Aggregate	Required	N/A	All greater than 80 MVA are needed in Network Model per RC requirements December 1, 2012 or have in place a transition mitigation plan with MISO
≥ 5MVA	Individual Generator	N/A	Required	If QF decides to have generator participate in the MISO Market, QF generator will be needed to be modeled in Network Model and Commercial Model by December 18, 2013

Data Confidentiality

MISO is a signatory to the North American Electric Reliability Corporation Confidentiality Agreement for Electric System Operating Reliability Data (ORD) and will hold data confidential per the agreement. Per the ORD Agreement, the only entities that may have access to the Operating Reliability Data must be both (i) directly responsible for immediate real-time operating reliability of a portion of the bulk power system or otherwise have a need for access to data concerning immediate, real-time operations of the bulk power system (including NERC and Regional Entities), and (ii) signatories to the ORD Agreement. Any data MISO receives from

QFs will be held confidential such that Operating Reliability Data is not made available to employees of any Merchant Functions (whether utility or private) who engage in the purchase or sale, at either wholesale or retail, of electric energy or capacity. In addition to the ORD Agreement, MISO has confidentiality obligations to Market Participants (MPs) under Section 38.9 of the MISO Tariff, which requires that MISO provide advance notice to the MPs before any of their non-public data is provided to third parties, such as governmental agencies, and that any disclosure will be made pursuant to appropriate protections.

Section 2: QFs in the MISO Reliability Coordination Area

The North American Electric Reliability Corporation (NERC) has been granted the legal authority by the Federal Regulatory Energy Commission (FERC) to enforce standards (Reliability Standards) established to ensure the reliability of the BES. NERC implements these Reliability Standards through regional reliability authorities. MISO is one of these regional Reliability Coordinators (RCs). MISO will assume the RC function for the Entergy region at such time as it begins to perform the role of the Independent Coordinator of Transmission (ICT), which is scheduled to occur on December 1, 2012. As the RC, MISO will implement and maintain state estimator and contingency analysis capabilities for the entire Entergy regional bulk power transmission system. This will require that MISO's Network Models incorporate information regarding all of the generating facilities, including QFs, with large real or reactive power components that are interconnected to the BES. The Network Model reflects all generating facilities interconnected with the BES because the Network Model is one of the essential tools used to maintain reliability of the BES in real time.

As with all other generators greater than 80 MVA, QFs are required to provide the RC – MISO, in this instance – with information that MISO deems necessary to ensure the safe and reliable operation of the BES. This requires that QFs provide MISO with a basic, minimum level of design information (e.g., one-line diagrams), real-time SCADA analog and status data, and outage information required for reliability coordination. If a QF decides to engage as an active Market Participant in the MISO markets with QF generation, more detailed modeling and revenue quality metering may also be needed.

All QFs within the Entergy Balancing Area must either meet the reliability requirements listed above or have in place a transition mitigation plan to adequately include their facilities in MISO's monitoring capabilities mutually acceptable to MISO, the applicable Entergy Transmission Operator function, and the QF. The transition mitigation plan will describe the physical limitations that prevent the QF from meeting the requirements, timing for when the facility will meet the requirements, and how reliability will be managed in the interim. MISO is currently in the process of applying the same criteria and requirements to existing QF generation within its Reliability Coordination footprint.

Roles and Responsibilities of the RC

As the RC, MISO has an obligation to monitor and provide reliability instructions to participants within the BES within its entire footprint to ensure reliable operations. The discharge of this obligation requires MISO to determine generator data requirements and establish standards for the provision of that data. NERC has established a series of Standards that set out the roles and responsibilities of the RC. These include:

- Standard IRO-003 R1: Each Reliability Coordinator, including MISO, shall monitor all Bulk Electric System facilities, which may include sub-transmission information, within its Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.
- Standards IRO-010 R2 and R3: MISO, as the RC, has the responsibility to distribute a data specification to entities that have facilities monitored by the RC, and the entities that own or control those facilities are obligated, under Federal law, to provide the data that MISO requires.
- IRO-005 R1.1 and R1.8: MISO, as the RC, is required to monitor the status of generators and planned generation dispatches. Per NERC standards, generator operators need to comply with MISO's data specification.
- NERC standards TOP-003 R1 and R1.1: Generator operators are required to provide next day generation outages to MISO, operating as the transmission operator.

Information that must be provided to MISO for Modeling and Telemetry (SCADA information)

The previous discussion determines ***which*** generating units must be included in the MISO Network Model. For each of those units, MISO needs both static and real time information. The static information is typically provided in the form of current one-line drawings of the generator and substation facilities that interconnect the generator(s) to the transmission system.

Telemetry is the data required in the "Balancing Authority Functional Alignment and Ancillary Service Market Implementation ICCP Data Exchange Specification." All individual generating units greater than 80 MVAs gross, or single contingency loss of multiple units of greater than 80 MVAs gross, must be explicitly modeled in the MISO Network Model and provide the real-time telemetry specified below for RC purposes. Also, one-line diagrams depicting the electrical configuration of such units must be provided to MISO.

For those larger units that require real-time operating data, MISO expects the following output information to be telemetered on a 2 second refreshed basis in accord with section 3.4 of RTO-SPEC-005 ASM ICCP Data Exchange Specification (https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=117550) and MISO Tariff (https://www.misoenergy.org/_layouts/MISO/ECM/Download.aspx?ID=19218) Sections 38.2.2b, 38.2.2e, 38.2.2g, 39.2.5a:

- Unit MW (Reliability and Market)
- Unit MVAR (Reliability and Market)
- Unit Breaker Status (Reliability and Market)
- Unit Control Mode (Market) – i.e., capability to respond to MISO dispatch instructions
- Echo Resource Setpoint Measurement (Market) – i.e., confirmation of receipt of setpoint instructions

Outage Coordination

MISO coordinates and assesses the impact of all generator outage schedules in the MISO Reliability Coordinator Area. It is essential for generation owners / operators to provide MISO their outage schedules such that impacts may be assessed in the next day planning study, outage coordination studies, as well as transmission seasonal assessment studies. Outage schedule analysis may include power flow, contingency analysis and stability analysis as necessary to ensure the safety of the transmission system.

The need for outage information and requirements for submitting outages are defined in the MISO Business Practices Manual (BPM) 008 – Outages Operations (https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19184). Section 1.3 identifies the respective FERC and NERC directives on outage coordination. Coordinated Seasonal Transmission Assessment (CSA) study is performed under the requirements of the NERC TPL Standards. MISO recognizes that the extended notice requirements for planned outages of utility generation including nuclear and coal units may not be consistent with the operating needs of QF generation due to its close integration with the production plans and steam and power requirements of the QF load. The key is for QFs to provide MISO as much advance notice as possible of planned downtimes.

Un-planned outage schedules shall be submitted to MISO as soon as identified and if considered a Forced outage should be submitted within 30 minutes of the event.

Outage information that is submitted to MISO will be treated as confidential, commercially sensitive information pursuant to FERC Order 2000, Transmission and Generation Maintenance Approval, Section III.D.4 Short-Term Reliability (Characteristic 4), and will not be made available to competitors or other market participants.

Back-up Power and Capacity Requirements

Under PURPA, QFs have the right to purchase supplementary power, back-up power, maintenance power, and interruptible power at retail rates which are just and reasonable, based on accurate data, and consistent system-wide costing principles, and that apply to the utility's other customers with similar load or cost-related characteristics.

Hybrid QFs that register in the Commercial Model have the opportunity to become a Capacity Resource using capacity that exceeds its host load. A QF will receive an Unforced Capacity (UCAP) value for the resource that can be used toward Resource Adequacy requirements. (Please reference BPM 011 – Resource Adequacy (https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19206) for more information.) To be utilized as a Capacity Resource, the UCAP value is converted to Zonal Resource Credits (ZRCs) and designated accordingly. QFs must then submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, for the Installed Capacity value of the Capacity Resources converted to Planning Resource Credits (PRCs) for each Hour of each day during the Operating Month, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment, except to the extent that the Capacity Resource is unavailable due to a full or partial forced or scheduled outage.

Commercial and Network Model Requirements

Applicability

MISO has issued a series of "Business,Practice Manuals," available on MISO's website at https://www.midwestiso.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx,.

A brief discussion of some of the key points that may be found in those BPMs is excerpted below. Note, however, if a QF decides to engage as an active participant in the MISO markets, more detailed modeling and revenue quality metering may also be needed.

[BPM-010]3.1.1 Resource Modeling
MISO's general policy is that all Generation Resources greater than or equal to 5 MW that are registered to participate in the Energy and Operating Reserve Markets must be represented in both the Commercial and Network Models. Additionally, applicable Resources (currently >80 MVA) that are not registered to participate in the Energy and Operating Reserve Markets but that are within MISO Reliability Coordination Area must be represented in the Network Model for reliability coordination. Please refer to BPM 10 (https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19186) for more information.

Section 3: QFs in MISO Market/Balancing Authority Area

At a minimum, QFs must meet MISO RC Area requirements described above. In addition, QFs choosing to participate in the MISO market will need to meet requirements described below. QFs may choose from one of two options relative to participating in the MISO market:

Behind the Meter Option

QFs may keep all of their facilities behind the meter and not participate directly in the MISO market. Under this option, a QF would still be able to "put" excess energy to its host utility pursuant to the host utility's tariff. The incumbent Entergy Operating Company will include the behind the meter generation in a load CP node that is owned by the incumbent Entergy Operating Company for each QF customer that does not become a Market Participant and register this load Asset in the Commercial Model. QFs will be modeled as behind-the-meter generation and net injection would be placed into a load CP node. This option will require revenue quality metering at the point of injection. MISO will settle with the applicable Entergy Operating Companies according to MISO's tariff.

Hybrid Option

QFs that register in the Commercial Model and become MISO Market Participants will be eligible to participate (i.e., submit offers or self-schedule) in both the day-ahead and real-time MISO markets up to the maximum amount (i.e., generator's maximum capacity minus expected host load). If the QF generation will not be used to serve host load, then participation in the market for QF generation under this option can be up to 100 percent of the generator's capacity. Under this hybrid approach, QFs will effectively separate their generation into a portion that serves their host load and a portion that will be able to participate directly in the MISO Market. The portion of the QF generation participating in the market would be registered by either the QF or an agent of the QF.

QFs that register in the Commercial Model and participate as MISO Market Participants:

- May register generation in the market and offer net excess to the market on a day ahead, real time basis, and excess capacity subject to market business practices and tariff requirements,
- May withdraw supplemental, backup or maintenance energy for host load pursuant to the applicable retail rate,
- Will be required to provide revenue quality metering data for each of their commercial pricing nodes in the market,
- Will need to provide MISO adequate metering and data to verify that flexible economic resources offered and accepted in the real time market are following dispatch

instructions. This verification is needed to ensure market dispatch is effective in managing constraints, and

- Will be required to have Automatic Generation Control (AGC) for resources offering regulation into the market. (NOTE: The energy market has a 5 minute periodicity, so AGC is encouraged but is not required.)

QF resources participating in the market via the hybrid option may not "put" energy to the incumbent Entergy Operating Company, although they will be able to deliver unscheduled energy to the MISO real-time market subject to the rules that apply within that market. This is required to ensure net total injection of the QF resource to the market is consistent with market dispatch.

Financial Schedules

The MISO Market facilitates the transfer of MWhs from one Market Participant to another through the use of Financial Schedules. Financial Schedules may be created for the financial transfer of MWhs in either the day-ahead or real-time market. Financial Schedules may be used by any Market Participant, and therefore apply to both the behind the meter and Hybrid Options.

For instance, if a QF that is registered as a MISO Market Participant were to inject 10 MWh into MISO, it could create a Financial Schedule to sell those MWhs to another Market Participant. By selling the 10 MWh using a Financial schedule, it would net against the 10 MWh injection, resulting in a $0 energy settlement with MISO. In turn, the Market Participant buyer would pay the Seller for the MWh at the contracted rate agreed upon between the two parties. The financial schedule between the parties would assign responsibility for losses and congestion costs. A QF Market Participant could thus use a Financial Schedule to make a bilateral sale to its host utility.

Please refer to BPM 002, Section 4.1.2 for more information (https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19178).

Physical Schedules

Physical Scheduling rules are explained in MISO BPM 007, Physical Scheduling, which is posted on MISO website: https://www.midwestiso.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx. At the same location, MISO BPM 013, Module B – Transmission Service is also posted. BPM 013 explains MISO rules regarding transmission services.

If a QF owner, or its agent, is registered as a MISO Market Participant, the owner can export any extra power from the QF to areas outside of MISO market (outside the MISO BA). To do this, the owner must submit an export tag (called a "transaction") to the MISO day ahead and/or real time markets. The owner also needs to obtain export point to point transmission service from the MISO OASIS to support the transaction before the owner can submit the day ahead and/or real time tag.

As an eligible Market Participant, the owner has the right to engage in any other import / export transactions like any other market participant, not necessarily related to the QF facility.

Appendix A: Market Integration Generator Readiness Requirements

This section describes the generator readiness requirements necessary for generators, including QFs, to integrate into the MISO market on December 18, 2013. If the generator plans to participate in the MISO market, or maintain the option to do so, then the following Market Integration requirements apply.

- All generators greater than or equal to 5MW that are directly connected to MISO's Transmission System and participating in MISO markets shall be modeled explicitly in the Network Mode and commercial model. Generators modeled in the Network Model must have real-time telemetry (MW, MVAR, Status) or they will be considered behind the meter and be price takers only. See https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx
- Generators selling regulation service must have the ability to receive and comply with dispatch signals every 4 seconds, so the activation or installation of Automatic Generation Control is required. For generators selling flexible economic generation for MISO dispatch, a five-minute response is required (installation of AGC control is strongly recommended). Timeframe: ASAP to be completed by closed loop testing (August 2013 to October 2013). Prior to market integration, NERC requires MISO to conduct closed loop testing to ensure generation signals can be received and responded to. Timeframe - June 2013 to October 2013
- Submit Market Participant registration no later than December 1, 2012
- Assuming MP certification is obtained, the generator may submit Asset Registration (Commercial Model Information) no later than June 1, 2013

Note 1: these same requirements apply to the Entergy Operating Companies and any embedded entities that currently have direct connectivity with the SOC.

Note 2: Generators that will not participate in the MISO market and do not want to maintain the option of participating are not required to meet the requirements above.

Requirement	Timeframe
If metering on the generator is needed per requirements detailed above / net metering is insufficient)	ASAP
Telemetry (Utilize existing or install communication system with Entergy Systems Operation Center (SOC) or in certain circumstances install WAN equipment for ICCP communication directly with MISO) • **If a Generator seeks to install WAN equipment for a direct ICCP connection to MISO, the Generator is required to cover the purchase of the equipment, at an approximate cost of $8,000, and pay a monthly fee of up to $1,500 for the high speed phone line.**	ASAP if no existing communication with SOC to either SOC or MISO
One line Diagram information must be incorporated into the MISO network Model (direct submittal to MISO preferred)	ASAP
Generator Outages >10 MW must be reported into MISO's Outage Coordination System CROW (via Entergy Systems Operation Center (SOC) or in certain circumstances directly with MISO)	ASAP

The table below provides a summary of the requirements and impacts of the Entergy Operating Company's and the QF's activities by various MISO functions.

MISO Function	Requirement/Impact
Reliability Coordination (Monitoring)	• Requires explicit modeling of generators and LBA loads. • Real-time metering is required to provide ICCP/SCADA information. • Applies to >80 MVA QFs connected at >=69 KV, whether behind the meter or Hybrid.
Commercial Model	• The Entergy Operating Company would be the Market Participant for BTM QFs, while the QF or its agent would be the MP for Hybrid QFs. • Net output would be aggregated into a Load Zone CPNode for BTM QFs and into a Gen CPNode for Hybrid QFs. • Revenue quality metering is required. • Load would remain as Retail.
Auction Revenue Rights/Financial Transmission Rights	• Load associated with a QF would only be eligible for an allocation of ARRs to the extent it has Transmission Service that qualifies for such an allocation under MISO's tariff.
Day-Ahead Market	• The Day-Ahead Market cannot receive offers for surplus BTM generation (negative MW bids are not allowed for a Load Asset) • Hybrid QFs can submit offers and/or self-schedule for their surplus Gen-to-Market. • Virtual Bids could be used to hedge Day Ahead vs. Real-Time prices. Please refer to the MISO Credit Policy for virtual activity market rules.
Real-Time Market	• Hybrid QFs can submit offers and/or self-schedules for their surplus Gen-to-Market. • When the CPNode has net injections or withdrawals in comparison to its Day Ahead Schedule, it is a price taker and will receive appropriate imbalance charges.
Transmission Service	• The applicable Entergy Operating Company, as the Load Serving Entity, would need to designate the net withdrawals as a Network Load

MISO Function	Requirement/Impact
	• QF would settle with Entergy directly per the appropriate Entergy Operating Company Retail Tariff requirements.
Market Settlements	• The applicable Entergy Operating Company, as the Load Serving Entity, would be responsible for all market charges and they would be settled at the CPNode that includes the QF generation and load. • QF would settle with Entergy directly per the appropriate Entergy Operating Company Retail Tariff requirements.
Transmission Settlements	• The applicable Entergy Operating Company, as the Load Serving Entity for the QF load, would pay for Network Service for the net withdrawal
Interconnection Service	• If the QF's are tied to an Entergy Operating Company's transmission facilities placed under the MISO Tariff then all QF uprates and/or retirements would need to go through the MISO processes

Appendix B: Behind the Meter and Hybrid Configuration Examples

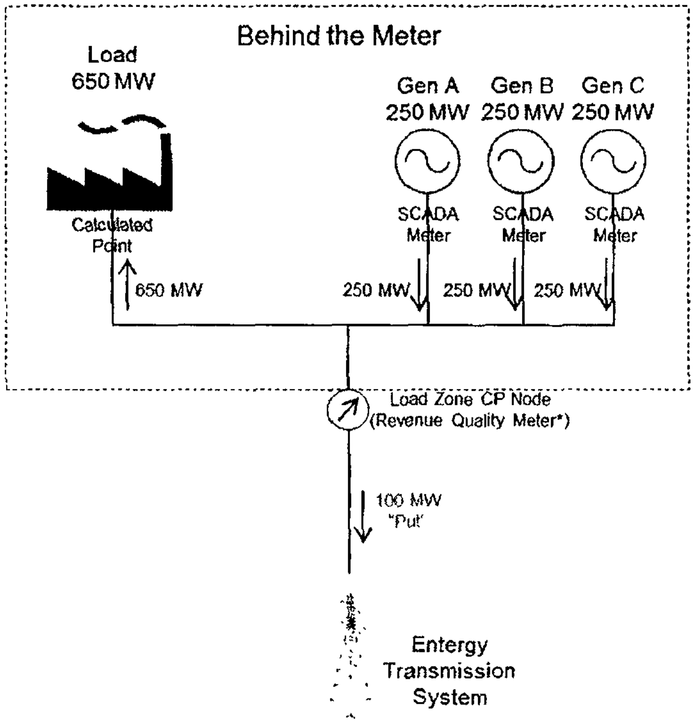
The following diagrams illustrate how the Behind the meter and "hybrid" approaches discussed above will be modeled. Please note QFs participating in the hybrid will have to provide revenue quality meter data that reflect their operations and net injections into the MISO market for settlement purposes.

All generation participating in the Day-Ahead or Real-Time Market are subject to the following:

- Changes to Commercial model arrangements can be made on a quarterly basis per MISO modeling practices
- Generator parameters can be changed on an hourly basis per market operations practices
- Generators participating in the Day-Ahead market will be required to follow Real-Time dispatch instructions
- Generators participating in the Real-Time market will receive four second dispatch, ancillary clearing and setpoint instructions. See Section 6.9 of Balancing Authority Functional Alignment and Ancillary Service Market Implementation ICCP Data Exchange Specification."

Example 1: Behind the Meter Configuration (QF Sale)

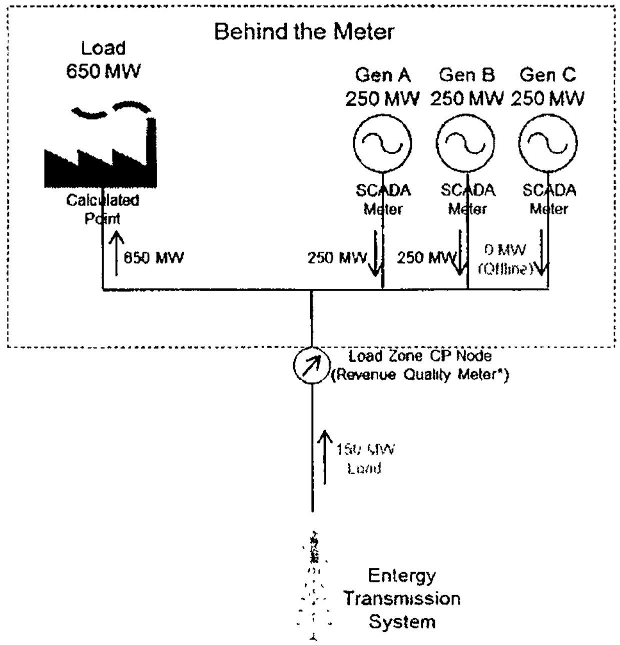
In a strictly behind the meter configuration, the Qualifying Facility's surplus generation would be "put" to the applicable Entergy Operating Company, and the QF would be compensated based on that Operating Company's avoided cost rate.



* - Meter may be single or multi-directional

Example 2a: Behind the Meter Configuration (QF Purchase)

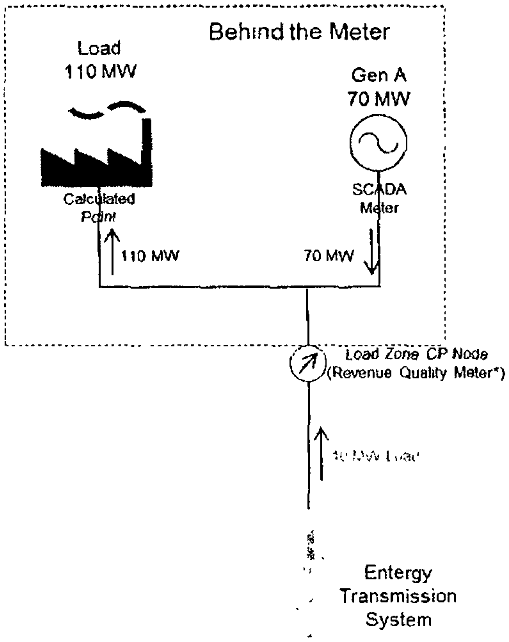
Under that same behind the meter configuration, where a Qualifying Facility's generation is not sufficient to serve its load, the incremental generation would come from the applicable Entergy Operating Company's system; the Entergy Operating Company bills QF at the retail "backup or maintenance power" rate.



* - Meter may be single or multi-directional

Example 2b: Behind the Meter Configuration (QF Net Purchaser)

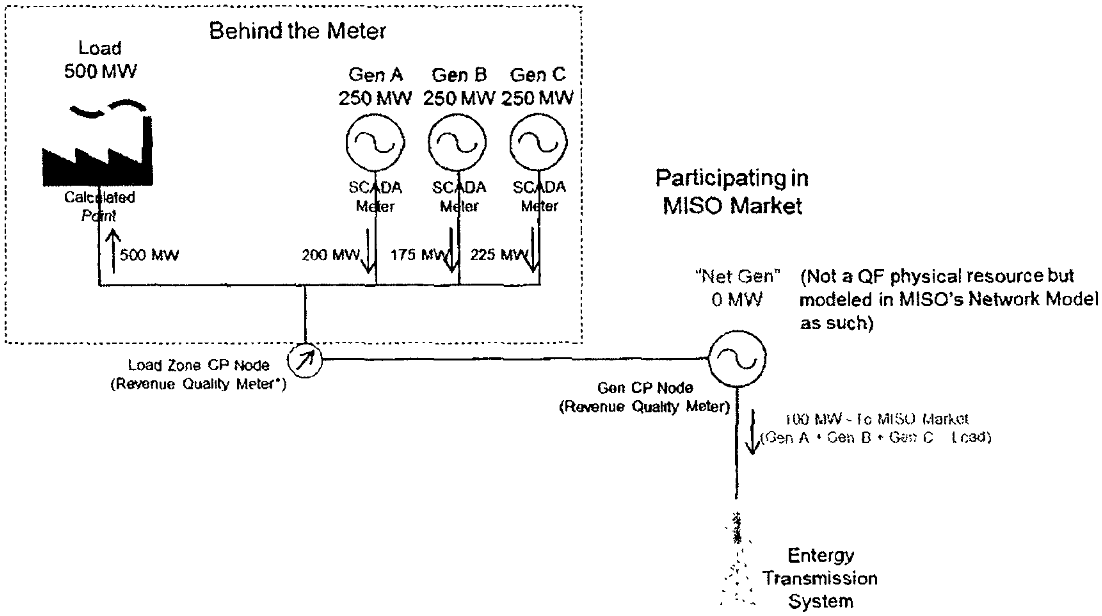
Under that same behind the meter configuration, where a Qualifying Facility's generation is not sufficient to serve its load, the incremental generation would come from the applicable Entergy Operating Company's system; the Entergy Operating Company bills QF at the retail "supplemental power" rate.



* - Meter may be single or multi-directional

Example 3: Hybrid Configuration (Normal Operations)

In the hybrid configuration, a portion of a Qualifying Facility's generation resources would serve host load, while the remainder would participate directly in the MISO Market, as illustrated below. MISO would model a "pseudo" generator in its Network Model as the source of those net flows to the market.

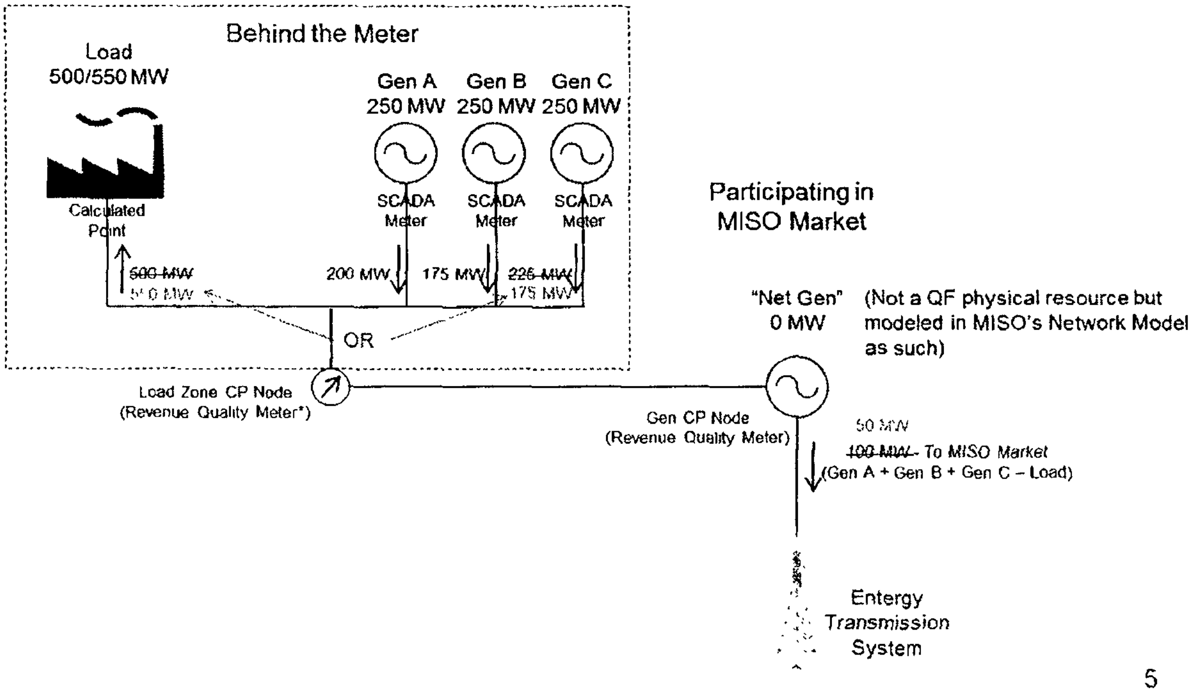


4

* - Meter may be single or multi-directional

Example 4: Hybrid Configuration (Congested System)

In the same hybrid configuration, assume congestion on the system results in MISO dispatching the flexible economic "Gen to Market" down from 100 MW to 50 MW to mitigate the constraint. This reduction could be achieved by some combination of a decrease in total output of QF generation or an increase in QF load. MISO has no preference but must have the ability to monitor flows to ensure congestion relief has been achieved.



5

* - Meter may be single or multi-directional

Frequency of Power Purchases from SWEPCO to Serve Eastman's Load

2016 to 2020

	2016	2017	2018	2019	2020	Total
Number of Net Import Hours[1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Percentage of Year	0.9%	4.3%	0.1%	1.9%	4.6%	2.4%

Notes:

1. Represents the number of hours in which Eastman was importing power during either forced or planned outages of its on-site generation facilities

[THIS PAGE INTENTIONALLY LEFT BLANK]